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Demand side flexibility from residential heating to absorb surplus renewables in low carbon futures

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ABSTRACT

Higher penetration of renewable sources of energy is essential for mitigating climate change. This introduces problems related to the balance of supply and demand. Instances in which the generation from intermittent and inflexible sources is in excess of system load are expected to increase in low carbon futures. Curtailment is likely to involve high constraint payments to renewable sources, and failing to curtail threatens the stability of the system. This work investigates a solution that makes use of residential heating systems to absorb the excess generation. Consumers are incentivised to increase consumption via a demand turn up mechanism that sets the electricity price to zero when excess generation occurs. The reduction in electricity price significantly weakens the economic case of dwelling-scale micro-cogeneration units. But technologies that use electricity are able to charge the thermal store when free electricity is available and discharge it when electricity prices are high. Such actions reduce the equivalent annual cost by 50% for a resistive heater and by 60% for a heat pump. Without disincentives, resistive heaters are likely to be chosen over heat pumps since they are easy to install, do not involve high upfront costs and can provide significant economic benefits.

1. Introduction

As governments take action to achieve climate change mitigation [1], the energy mix is likely to include substantially larger proportions of solar and wind energy. High penetration of these sources leads to an energy system that is significantly different from the one seen today. Generation is tied to the vagaries of weather conditions: the factors that determine the magnitude of output, sunshine and wind speed are outside human control. At low penetration levels conventional dispatch-able units can be used to maintain quality and reliability of power supply. But the same cannot be said about potential futures where penetrations are much more significant.

Traditionally when generation exceeds demand, some power plants are asked to lower output in order to maintain system stability. This is achieved through the balancing mechanism. Fossil fuel generators pay to turn down output since they can save fuel. But renewable sources participating in the balancing mechanism have no such incentive since there is no fuel cost. On the contrary, turning down output is detrimental to the renewable source's business case as it loses out on subsidies it would have received if it were injecting that electricity into the grid. Today, such a situation is encountered when the electricity generated by the wind farms in Scotland cannot all be transmitted to England. If these power plants are asked to reduce their output, they charge the system operator a fee that is far in excess of the subsidies that they forgo [2]. As the frequency of instances in involving surplus electricity is likely to increase with increasing penetration of renewable sources [3], the system operator needs a solution that can help avoid expensive constraint payments.

One potential way to tackle this problem of surplus electricity is to make use of the demand side of the electricity grid. The net load on the system could be modified such that it supports the needs of the supply side. This is known as Demand Side Management (DSM). As we move away from an energy mix dominated by fossil fuel to one dominated by solar and wind we are also transitioning to a system where demand can become a potent resource for balancing the system, where previously only the supply-side performed this task. DSM is likely to play a prominent role in such a future since in addition to economic savings it also provides system operators with a plethora of benefits: an additional source of flexibility to handle contingencies, congestion management, deferring network

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reinforcement and avoiding investment in peaking plants [4].

1.1. Previous literature

Surplus generation in an energy system has been studied by Lund and Munster [3]. Power injected by wind and cogeneration are decided by factors other than the variations in demand. This issue is of prime interest in this reference since wind and cogeneration account for more than half of the electricity production in the energy system considered by Lund and Munster [3]. Their energy system model analyses this problem by taking a national level or macro perspective. This means that the different sectors are aggregated into single entities. Another feature of the model is that it is meant to plan energy investment strategies. Three measures are suggested by the authors, the curtailment of wind generation, curtailment of cogeneration units and replacement of boilers with heat pumps. The first two measures avoid surplus production and the final one introduces flexibility to absorb the surplus. The results reveal that the cost of avoiding surplus is lesser than investing in high voltage transmission lines and that investing in flexibility reduces surplus production.

Pensini et al. [5] study whether excess renewable generation can displace fossil fuels used to supply heat. A hundred percent renewable scenario has been considered. The authors argue that using excess electricity to supply heat is more cost effective than investing in large scale electrical storage. This is done either through the use of heat pumps or resistive heating. Heat pumps are part of a district heating system that also includes thermal energy storage in the form of hot water tanks. Resistive heating systems along with high temperature storage units are present in the individual households. The excess electricity is distributed among the houses in this case and conversion takes place locally. In each case a natural gas boiler is installed for backup. The results indicate that heat pumps with central storage perform better in most cases except when zero cost electricity is available. Resistive heaters perform better in this case.

The excess electricity profile in Ref. [5] was generated from a different model by Budischak et al. [6]. The focus of this study was to analyse whether large penetrations of renewables and storage can satisfy demand for a given fraction of hours. As the greatest values of excess electricity was observed to occur in winter, the authors chose to analyse the supply of heat. This was done offline after the cost optimum of renewable investment was determined. It was seen that there a great match between the excess generation and demand for heat between November and May. Although this match is based on monthly aggregated values, it is an encouraging prospect that requires further research.

The work of Papaefthymiou [7] investigates how heat pumps can help integrate wind power through demand side flexibility. It makes use of passive storage within the building. Thus the temperature profile decides maximum available storage capacity at any point of time. This information generated from a building stock model which then relays it to a unit commitment model. The unit commitment model determines market prices, plant dispatch and the income of power plants. Thus this reference integrates the thermal model of the building stock with a high level electricity market model. Future scenarios for the German energy system in the year 2020 and 2030 are considered. Demand response actions are deviations from the business-*as*-usual heat driven operating strategy. The results indicate that demand side management is a viable alternative to conventional storage to help integrate wind power.

Hedegaard and Balyk [8] propose an approach to incorporate heating system operation into energy system models. The case study considered is the Danish energy system in the year 2030. Heat pumps and thermal storage tanks are used as instruments of demand side management. The energy system model optimises investment in generation, storage and transmission capacities and operation of the overall system. The buildings are assumed to make use of a constant temperature setting. Hence heating profiles can be generated for this temperature setting. However, the inclusion of demand side management allows the temperature to vary within a tolerance band that is different during the day and at night. The system is seen to invest in intelligent thermal storage to take advantage of these opportunities. Contrary to expectation, houses with lower insulation show greater potential for storage use. This is due to higher space heating demand in these houses enabling a higher potential benefit in absolute terms. Since both investment and operation is considered, the model can prioritise heat pump during periods with low marginal costs and shift it away from peak periods.

Another set of models consider integration of the operational aspects of both the electricity supply side and the electrical heating devices in the consumer side into one monolithic optimisation problem. The work of Patteeuw et al. [9] determines the carbon dioxide abatement cost of residential heat pumps with active demand side response. The authors compare the abatement cost of installing a heat pump with instead of a natural gas boiler. The heat pump is also equipped with a thermal energy storage unit. The structure of this problem is as follows.

The objective function is to minimise the operating cost of conventional generators. This is subject to several constraints. The power balance constraint accounts for conventional and renewable generation on the supply side and fixed and flexible demand on the consumer side. There are several factors such as ramping, minimum up time and minimum down time that need to be accounted for the generators to operate. Finally the heating devices also have associated constraints such as capacity, coefficient of performance and storage capacity.

This optimisation problem is solved with a time step of 1 h over a planning horizon that is one week long. The results are meant to provide an upper bound on the potential emissions savings that can be attained through the use of this technology. The future scenario based on Belgium is dominated by Combined Cycle Gas Turbines and Open Cycle Gas Turbines with comparatively lower levels of renewable penetration. Only single family residential households are considered on the consumer side. The results indicate that heat pump deployment decreases renewable curtailment. Though heat pumps contribute to peak demand, the use of demand response helps counter these effects. The level of renovation has a strong influence on emission savings. Abatement costs for mildly renovated buildings is high since emission savings are low. Thoroughly renovated buildings on the hand result in much lower abatement costs and emissions. Application of demand response is seen to reduce emissions and peak demand at the household level. A similar model is employed in Ref. [10] with the inclusion of resistance heating in addition to heat pumps. The authors also discuss different representations of the supply side such as a detailed unit commitment model and a merit order dispatch model. Merit order models are seen to provide a good approximation of performance at considerably lower computation times. For this reason, the merit order representation is used in Ref. [11] to study the impact of market penetration of demand response enabled devices. Increased penetration drives the overall operational costs down. This study also investigates the changes in economics of the individual household. As penetration increases, the extent to which the individual consumer has to react decreases. Hence, the savings decrease from the household perspective.

In a variation from the previous references which studied the use of electrical heating, the work of Alahaivala et al. [12] considers a cogeneration system. The thermal energy storage tank has been equipped with a resistive heater in order to increase demand in case the situation calls for it. The cogeneration unit uses an internal combustion engine as its prime mover. A natural gas boiler is installed as a fall back. Heat demand is generated using a dynamic building simulation model. Hourly electricity prices are extracted from the electricity spot market. In this case the consumer can also play the role of generator due to the cogeneration system. The question is whether the occurrence of surplus electricity will diminish the economic case for the cogeneration unit. Since a present day energy system is considered, the frequency of occurrence of surplus generation (and hence low electricity prices) is not high and the carbon intensity of the central grid is high. Thus these factors do not impede operation and the performance improves when optimal control is used to control this setup.

The provision of demand response from a cogeneration unit based on a price signal has also been studied by Houwing et al. [13]. The focus of this study is on the economic performance or the reduction in costs due to the installation if the cogeneration unit. Comparisons are made between a typical heat led strategy and an intelligent operating strategy based on model predictive control. Cogeneration units perform best when there is a large difference between electricity and gas prices. When real time electricity prices are used this value is diluted. Hence it was observed that strongly fluctuating electricity prices provide more scope for intelligent control and hence reduce costs to a larger extent in comparison to the baseline control strategy. The model predictive control strategy is seen to produce energy costs that are one to fourteen percent lower than that of the heat led strategy.

1.2. Novelty and contributions

The scope of this work revolves around three factors. First is the context of power system decarbonisation. Second is the use of a decentralised electricity price signal which is set to zero to incentivise consumption when surplus renewables are encountered. Finally, this work considers the comparison of performance of electrical heating and cogeneration for an individual household using optimised control. The intersection of these three factors is virtually untreated by previous literature as explained below.

Power system decarbonisation is the central theme of this work. Hence this work differentiates itself from Refs. [9–13] in this respect. Although the work of Patteeuw et al. [9,10] and Arteconi et al. [11] make use of a future scenario, they do not incorporate an energy mix which is dominated by low carbon sources into the model. Similarly, only present day energy systems are considered by Alahaivala et al. [12] and Howing et al. [13].

Next let us consider the decentralised electricity price signal which is set to zero at times. The works of Patteeuw et al. [9,10] and Arteconi et al. [11] assume that a single centralised coordinator has complete control over and knowledge about all the flexible resources connected to the system at all points of time. This is not practical due to large computational costs when several million units are involved. Issues related to privacy are another important drawback of this approach.

Other references which analyse overall energy systems [3,8] use aggregated representations of flexible resources since individual representation of all devices is not feasible. This representation also implicitly assumes that a centralised entity has control over all heating devices.

In Budischak et al. [6] excess renewables displace natural gas. This happens when the amount of renewable electricity available is greater than the load and available storage capacity. Budischak et al. [6] perform this analysis using conditional statements to determine dispatch decisions. The surplus renewables displace natural gas in the residential sector as a whole. This simplifying assumption is made since management of residential heating is not the focus of this study. Nevertheless this assumption also signifies centralised control. Another variant of such an aggregated representation can be found in Papaefthymiou et al. [7] where information from one reference building is scaled up to be incorporated into the unit commitment model. As this one building is the only deciding factor in this case it implies that all heating devices are controlled en masse, making it another centralised model.

It can be argued that Pensini et al. [5] is close to the scope of this work as it studies power system decarbonisation and the displacement of heating fuels. Firstly, this reference makes use of an aggregated thermal load; hence it does not provide a tool for coordinating multiple resources. Secondly, it only considers electric heating and does not compare performance of cogeneration units. This is also true of [7–11].

2. Background

2.1. Price based demand response

Historically demand side management was done through load curtailment. The system operator would either remotely shut down certain loads or offer discounts/payments to loads to shut themselves down [14]. But such a centralised approach is not suitable for large scale deployment of DSM. The computational effort of managing millions of appliances and privacy concerns over a single entity having access to all of the consumption data are major obstacles that stand in the way of a centralised system.

Consumers can be incentivised to modify their usage patterns without requiring access to information about each and every individual connected to the grid. This does not happen today since consumers pay a constant retail price for the electricity they use. Hence, the onus is on the utility to absorb the uncertainties related to net load variations. Since the consumers are not exposed to such variations they see no benefit in changing behavioural patterns to shift usage to periods that would reduce the stress and cost of supplying electricity. Implementation of a time varying electricity price can provide signals to the consumers to modify their load patterns.

Time varying electricity price signals have previously been implemented through the use of time-of-use tariffs. Such schemes have been showed to influence consumer behaviour to shift demand away from peaks periods [15,16]. Time-of-use tariffs vary over different times during the day, but the patterns themselves are not subject to regular change across days. Hence, such schemes are only meant to serve the long-term objective of reducing demand during periods which are historically associated with system peaks. But such repeating patterns are not enough to handle surplus renewables. The occurrence of such events is highly uncertain, irregular and difficult to predict. Another price-based scheme which is an improvement over time-of-use tariffs is Critical Peak Pricing (CPP). Here consumers receive reduced rated at non-CPP times, but are charged a premium rate for current drawn during a CPP event [17]. This scheme is also aimed at reducing system peaks or managing contingencies and cannot be used in its current form to handle surplus renewables.

The solution to this problem has to inherit the dynamic nature of CPP but has to induce an increase in demand instead of a decrease. This can be done by decreasing the electricity price in response to surplus renewables. But this does not mean we have to sacrifice the benefits related to peak pricing. The advantages of both approaches can be combined through the use of a real time pricing system that decreases prices when there is excess renewable electricity and increases prices during system peaks.

2.2. Implementation of real time electricity pricing

In practise, setting one single price signal that applies to all consumers is likely lead to rebound phenomena. Rebound phenomena are the trends resulting from a large number of consumers reacting to a change in the price signal. There is a possibility that the reaction from consumer side resources overshoots the desired change in load or generation. To prevent such instances from violating physical constraints different price signals need to be used for different groups of consumers. Advanced metering infrastructure will be necessary in order to implement real time electricity prices. Equipment such as the smart meters currently being used in the UK to measure real time demand will have to be updated to convey electricity prices as well. This will also require new IT solutions that can collect, store and process large amounts of meter data.

Another issue will be societal awareness and acceptance. Real time prices will require active participation from consumers. For this system to succeed, the public will need to be educated about electricity consumption and its impact on energy security. Making real time prices the default option and allowing customer to opt-out is likely to result in higher adoption rates than asking customers to consciously opt-in to the real time prices.

2.3. Controllable devices in residential heating systems

The dynamic nature of real time pricing exposes the consumer to the real cost of producing electricity. This could be viewed as a source of pain for the customer since the energy consumed by the house needs to be monitored continuously in order to be economical. On the contrary, with the help of controllable loads, demand side management can be achieved automatically without human intervention. Residential heating provides such controllable loads which can potentially serve as powerful resources that provide value to both the customer and the system operator. The main objective of such a system is to provide the customer with energy and cost savings without degrading the comfort level experienced by the occupants.

At the heart of such a solution lies a thermal energy storage unit. Storage is crucial since it provides the system with the ability to shift demand in time. Heat supply technologies act as a sink for electricity which store heat to be used at a later point. Electrical appliances such as a resistive heater or heat pump can supply heat. Another technology that could provide value is a combined heat and power unit. These devices can act as a source of electricity so that the customer can gain from peaks in electricity prices and the network can gain from distributed generation instead of dispatching a peaking plant.

3. Methodology

3.1. Model overview

The model used in this article builds upon the authors' previous work [18]. This work also involves an energy mix that is characterized by high penetration of low carbon sources coupled with an electricity price regime that makes use of the Long Run Marginal Cost of electricity. The main difference is in the handling of excess electricity generation. The system is said to have excess generation when renewable sources have to be curtailed to maintain system stability. Demand side resources are incentivised to increase consumption via a Demand Turn Up mechanism that sets the electricity price to zero during periods of excess electricity generation.

This approach to Demand Turn Up has been adopted since there is no previous basis related to tackling this challenge. The price is set to zero to mimic conditions that would be encountered in an electricity price regime based on the status quo, namely, the Short Run Marginal Cost of generation. In the short run electricity price regime, excess renewable generation would result in zero or negative electricity prices. While negative prices would obviously improve the economics of the heating system, it is not expected to result in an operating strategy that is different from one that makes use of zero electricity prices. Detailed descriptions of the power dispatch model and electricity price regimes have been covered the authors' previous works [18,19]. The following sections will focus on the consumer side model.

3.2. Individual heating system description

This model compares the operation of four different technologies within an individual household: a resistive water heater, a heat pump, a fuel cell micro cogeneration unit and a Stirling engine micro cogeneration unit. The different options considered are summarised in Table 1. The baseline case makes use of natural gas boiler for heat and a connection to the central grid for electricity. The natural gas boiler is an auxiliary heat source for all the cases except the heat pump. The connection to the central grid is a supplementary source of electricity for all cases. All new technologies are also equipped with a thermal energy storage tank. The system is exposed to time varying electricity prices, import is charged at retail price and export attracts revenue at wholesale price. The inputs from the power dispatch model provide the wholesale price. Wholesale prices are uplifted by taxes, fuel duties and policy cost recovery based on data from the UK government [20] to calculate retail prices. As explained earlier, the house is offered free electricity from the central grid when there is excess renewable generation.

3.3. Mathematical model

The model makes use of a mixed integer linear program. It is applied to a set of representative days in a year (see Appendix A for sample say selection algorithm). Each day is divided into 5 min intervals. The results from each day are weighted approximately equally to calculate the annual performance indices used for comparison. The structure of the optimisation problem can be summarised as:

- Objective
  - o Minimise operating cost (for CHP this includes revenue from electricity export)
- Subject to
  - o Electrical and thermal load balance
  - o Feasible operating envelope
  - o Thermal energy storage operation

Equations describing the objective function and constraints are presented below. For the resistive heater and heat pump, the

Table 1
Heating technology options.

Case	Heat	Electricity
Reference	Boiler	Grid import
Resistive heater	Boiler, Resistive heater Thermal Energy Storage	Grid import
Air source heat pump	Heat pump Thermal Energy Storage	Grid import
Micro-CHP	Boiler, Micro-CHP Thermal Energy Storage	Grid import, Micro-CHP

objective function only consists of operating costs as shown in Equation (1).

$$\lambda = \sum_{t \in T} (\beta_t) \tag{1}$$

For micro cogeneration units the objective includes revenue from the export of electricity as shown in Equation (2).

$$\lambda = \sum_{t \in T} (\beta_t - \gamma_t) \tag{2}$$

Operational costs are the cost of natural gas and electricity imported. The cost of natural gas includes a fuel cost and a carbon cost. For the resistive heater this describes consumption of the boiler and the overall electrical demand including heater usage as shown in Equation (3).

$$\beta_t = \left(\frac{B_t}{\eta_B}\right)(\alpha_{gas} + \alpha_{CO2} e_{gas}) + P_t^{imp} \alpha_t^{imp} \tag{3}$$

For the heat pump, only electricity is consumed as this does not include a boiler as shown in Equation (4).

$$\beta_t = P_t^{imp} \alpha_t^{imp} \tag{4}$$

For the micro-CHP unit, gas is consumed by both the boiler and the micro-CHP unit. Electricity imported is added to cost as shown in Equation (5).

$$\beta_t = \left(\frac{P_t^{th}}{\eta_{th}} + \frac{B_t}{\eta_B}\right)(\alpha_{gas} + \alpha_{CO2} e_{gas}) + P_t^{imp} \alpha_t^{imp} \tag{5}$$

Export revenue is the product of electricity exported and the export price of electricity summed over all periods as shown in Equation (6).

$$\gamma_t = P_t^{exp} \alpha_t^{wholesale} \tag{6}$$

With regard to electrical power balance, generation and import are on the left side of the equation. Demand and export are on the right side of the equation. The components for the resistive heater, heat pump and micro-CHP are shown in Equation (7), Equation (8) and Equation (9) respectively.

$$P_t^{imp} = P_t^{RH} + D_t^{el} \tag{7}$$

$$P_t^{imp} = P_t^{HP} + D_t^{el} \tag{8}$$

$$P_t^{imp} + P_t^{el} = P_t^{exp} + D_t^{el} \tag{9}$$

When considering thermal loaf balance, heat supplied by installed technology and the natural gas boiler are on the left side of the equation. Demand and storage are on the right side of the equation. The components for the resistive heater, heat pump and micro-CHP are shown in Equation (10), Equation (11) and Equation (12) respectively.

$$B_t + \eta_{EH} P_t^{EH} = D_t^{th} + R_t^+ - R_t^- \tag{10}$$

$$COP_{HP} P_t^{HP} = D_t^{th} + R_t^+ - R_t^- \tag{11}$$

$$B_t + P_t^{th} = D_t^{th} + R_t^+ - R_t^- \tag{12}$$

The heat to power ratio governs the relation between thermal and electrical power supplied by a micro-CHP unit as shown in Equation (13).

$$P_t^{el} = \eta_{el}\left(\frac{P_t^{th}}{\eta_{th}}\right) \tag{13}$$

The following equations govern thermal storage operation. Current state of charge is a function of previous state of charge and the charging/discharging level in the current period as shown in Equation (14). The storage unit is not allowed to charge and discharge simultaneously according to Equation (15). Charging and discharging limits are governed by Equation (16) and Equation (17). The state of charge at the beginning of the planning horizon is the same as that seen at the end according to Equation (18). Storage capacity is defined by Equation (19).

$$S_t = S_{t-1} + \eta_{ch} R_t^+ - \frac{R_t^-}{\eta_{disch}} \tag{14}$$

$$\phi_t^+ + \phi_t^- \le 1 \tag{15}$$

$$0 \le R_t^+ \le \bar{S}\phi_t^+ \tag{16}$$

$$0 \le R_t^- \le \bar{S}\phi_t^- \tag{17}$$

$$S_1 = S_{T_{end}} \tag{18}$$

$$0 \le S_t \le \bar{S} \tag{19}$$

Each of the components: boiler, resistive heater, heat pump and micro-CHP have associated capacity limits. These are described by Equations (20)–(23).

$$0 \le B_t \le \overline{B} \tag{20}$$

$$0 \le P_t^{EH} \le \overline{P^{RH}} \tag{21}$$

$$0 \le P_t^{HP} \le \overline{P^{HP}} \tag{22}$$

$$0 \le P_t^{el} \le \overline{P^{el}} \tag{23}$$

This study focuses on the comparison of economic and environmental performance. Economic performance is measured in terms of the Equivalent Annual Cost (EAC) which is defined by Equation (24) for heating systems other than micro CHP and Equation (25) for micro CHP.

$$\Phi = \Psi \frac{r}{1 - \frac{1}{(1+r)^L}} + \sum_{k \in K} w_k \left(\sum_{t \in T_h} (\beta_t)\right) \tag{24}$$

$$\Phi = \Psi \frac{r}{1 - \frac{1}{(1+r)^L}} + \sum_{k \in K} w_k \left(\sum_{t \in T_h} (\beta_t - \gamma_t)\right) \tag{25}$$

Environmental performance is measured in terms of annual carbon emissions which is defined by Equation (26) for heating systems other than micro CHP and Equation (27) for micro CHP.

$$E = \sum_{k \in K} w_k \left(\sum_{t \in T_h} \left(e_{gas}\left(\frac{B_t}{\eta_B}\right) + e_{el} P_t^{imp}\right)\right) \tag{26}$$

$$E = \sum_{k \in K} w_k \left(\sum_{t \in T_h} \left(e_{gas} \left(\frac{B_t}{\eta_B} + \frac{P_t^{th}}{\eta_{th}} \right) + e_{el} P_t^{imp} - e_{el} P_t^{el} \right) \right) \quad (27)$$

3.4. Data used in the simulations

Natural gas prices are from the UK government's projections for the year 2035 [20]. Carbon prices are based on the non-traded price of carbon data in the UK government's valuation of energy use and greenhouse gas emissions [21]. The uplift of wholesale price to give retail price is based on projections generated by the UK government [20]. Capital costs in the year 2035 are within the ranges specified in Ref. [22] and cross-referenced with the UK TIMES model [23]. The electricity and heat demand profiles for the individual house are sourced from Ref. [24]. Further details are presented in Tables 2 and 3.

Specific upfront costs of heating technologies with reference to unit capacity have been presented below for the sake of completeness.

It is worth noting that data in the table above was taken from previous literature and is referring to specific upfront costs likely to be encountered more than fifteen years into the future. It is important to stress that such projections predicting phenomena decades in advance are highly uncertain. Thus, it is understandable that the ranges presented for specific upfront costs are not small.

4. Results and discussion

4.1. Comparison of operation

In this section we first compare the operation of the optimised residential heating system technologies with and without Demand Turn Up (DTU). As explained earlier, a Demand Turn Up event refers to the use of zero prices when there is an excess of renewable generation. The retail price of electricity is shown in the top row of each figure. The rest of the subplots describe electrical power balance, thermal power balance and operation of thermal storage. This discussion is followed by a comparison of overall performance that supports the conclusions.

Table 3
Specific upfront costs of heating technologies.

Technology	Specific upfront cost	Ref.
Boiler	44.6–89.9 (£/kW)	[23,24,39]
TES	0.09–8.9 (£/kWh)	[23,40,41]
Heat pump	238.9–299.3 (£/kW)	[22,23]
Fuel cell	2608.0–8705.3 (£/kW)	[22,23,34]
Stirling	335.4–4220.0 (£/kW)	[23,34]

4.1.1. Resistive heater

Operation with the original retail price of electricity is shown on the left side of Fig. 1. This price which is based on the Long Run Marginal Cost of electricity remains above 15 p/kWh throughout the day as seen in Fig. 1(a). Such high electricity prices do not provide scope for using the resistive heater as seen in Fig. 1(b). Consequently, the thermal energy storage unit does not charge or discharge as seen in Fig. 1(c) and (d). All thermal demand is met using the natural gas boiler.

The electricity price drops to zero at various points during the day if Demand Turn Up is active as seen in Fig. 1(e). As a result, the resistive heater is switched on when free electricity is available as seen in Fig. 1(f). The red curves in the negative direction in Fig. 1(g) represent charging of the thermal energy storage unit. This can also be seen through the corresponding increases in state of charge of the thermal storage unit in Fig. 1(h). Since free electricity is available at many points during the day, the system is able to charge the thermal storage unit to full capacity, discharge, and repeat this process more than once as seen in Fig. 1(h).

Table 2
Heating system parameters in the year 2035.[a]

Parameter	Description	Units	Range	Chosen Value	Ref.
α_{CO2}	Non-traded price of carbon	£/tonne	113	113	[21]
α_{gas}	Natural gas price	p/kWh	4.5	4.5	[20]
η_B	Efficiency of natural gas boiler	–	0.8–0.9	0.86	[25–29]
η_{ch}, η_{disch}	Charging/discharging efficiency of TES	–	0.4–0.97	0.9	[30–32]
η_{el} (Fuel cell)	Electrical efficiency	–	0.3–0.45	0.45	[33–35]
η_{th} (Fuel cell)	Thermal efficiency	–	0.39–0.48	0.45	[33–35]
η_{el} (Stirling engine)	Electrical efficiency	–	0.125–0.22	0.10	[36–38]
η_{th} (Stirling engine)	Thermal efficiency	–	0.6–0.8	0.80	[36–38]
Ψ (Boiler)	Upfront cost	£	2200–2500	2328.1	[23,24,39]
Ψ (TES)	Upfront cost	£	50–1300	415.4	[23,40,41]
Ψ (Heat pump)	Upfront cost	£	6449.0–9878.0	7587.3	[22,23]
Ψ (Fuel cell)	Upfront cost	£	3912–6059	5037	[22,23,34]
Ψ (Fuel cell reformer)	Upfront cost	£	240–3800	717.4	[23,42,43]
Ψ (Stirling engine)	Upfront cost	£	3376–4025	4193.4	[23,34]
$\overline{B}$	Capacity of natural gas boiler	kW	–	30	–
COP_{HP}	Coefficient of Performance of the heat pump	–	2–5.8	3	[44–46]
e_{el}	Carbon intensity of electrical grid	kgCO2/kWh	–	0.0753	[47]
e_{gas}	Carbon intensity of natural gas	kgCO2/kWh	–	0.1840	[48]
L (All heating options)	Lifespan	years	10–15	15	[33,34,36]
$\overline{P^{EH}}$	Capacity of resistive heater	kW	–	3.5	–
$\overline{P^{HP}}$	Capacity of heat pump	kW	–	27	–
$\overline{P^{el}}$	Electrical capacity of CHP unit	kW	–	1	–
r	Discount rate	%	–	3	–
$\overline{S}$	Capacity of thermal energy storage	kWh	–	5	–
w	Sample weights of representative days	Days	–	[91; 91; 91; 92]	–

[a] Note that a complete fuel cell micro-CHP system requires a fuel cell, fuel cell reformer, TES and boiler. The cost of the fuel cell is assumed to include all balance of plant except the reformer. Likewise a complete Stirling engine system requires a Stirling engine, TES and a boiler.

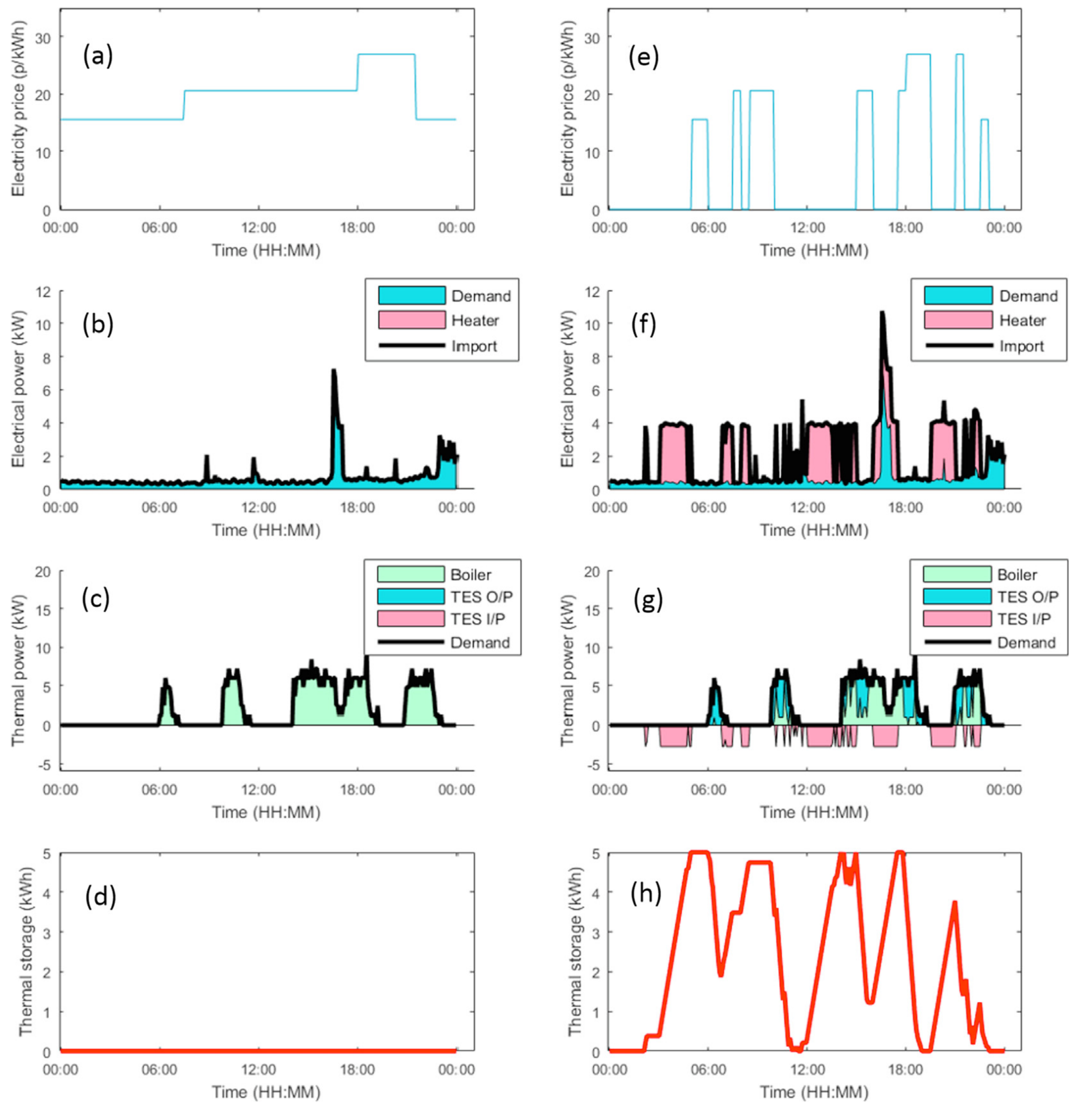

Fig. 1. Operation of the resistive heater: Without DTU ((a) to (d)) and with DTU ((e) to (h)).

4.1.2. Heat pump

The heat pump is different from the other technologies in the sense that it uses electricity to supply heat instead of natural gas. As a result of this, the shape of the electricity imported is influenced by the heat demand. The change in shape is clearer without DTU as seen in Fig. 2(b). In contrast to the resistive heater, the thermal storage unit is not completely dormant in this case. It stores up energy at the beginning of the day to supply heat demand when the electricity prices are above 25 p/kWh around 9 p.m. as seen in Fig. 2(c) and (d).

Reliance on electricity allows the heat pump to take advantage of the free electricity available with DTU. The red patches in Fig. 2(g) show the heat pump charging the thermal storage unit during such times. The blue patches in Fig. 2(g) show the heat pump discharging the thermal store when system has to pay for importing electricity. The shape of electricity imported does not follow heat demand with DTU since the use of the thermal storage unit shifts demand to periods with free electricity. As with the resistive heater, the system charges the thermal store to full capacity and discharges it more than once.

4.1.3. Fuel cell based micro cogeneration

High electricity prices and low natural gas prices are encountered when the system is operated without DTU. These conditions are conducive for the operation of fuel cell based micro cogeneration units as seen in Fig. 3(b). The coincidence of electricity and heat demand also favours the use of cogeneration as seen in Fig. 3(b) and (c). The efficiency gains from combined generation of heat and electricity are particularly clear when coincidence levels are high. The thermal storage unit allows the cogeneration unit to remain active continuously while storing up heat as shown in Fig. 3(d). This can be seen in the charging of the thermal store until 2 p.m.

The situation changes when DTU is enabled. The system no longer encounters high electricity prices throughout the day. Utilisation of the cogeneration unit is much lower as seen in Fig. 3(f) and (g) since it is more economical to use grid electricity and the natural gas boiler. The cogeneration unit is activated only when the electricity prices are high as seen by the sporadic appearance of blue patches in Fig. 3(f). This does not offer much scope for the thermal storage unit to be used as seen in Fig. 3(h).

4.1.4. Stirling Engine based micro cogeneration

The Stirling engine is different from the fuel cell in terms of heat to power ratio. It produces much more heat per unit of fuel consumed in comparison to the fuel cell. This means that unless a

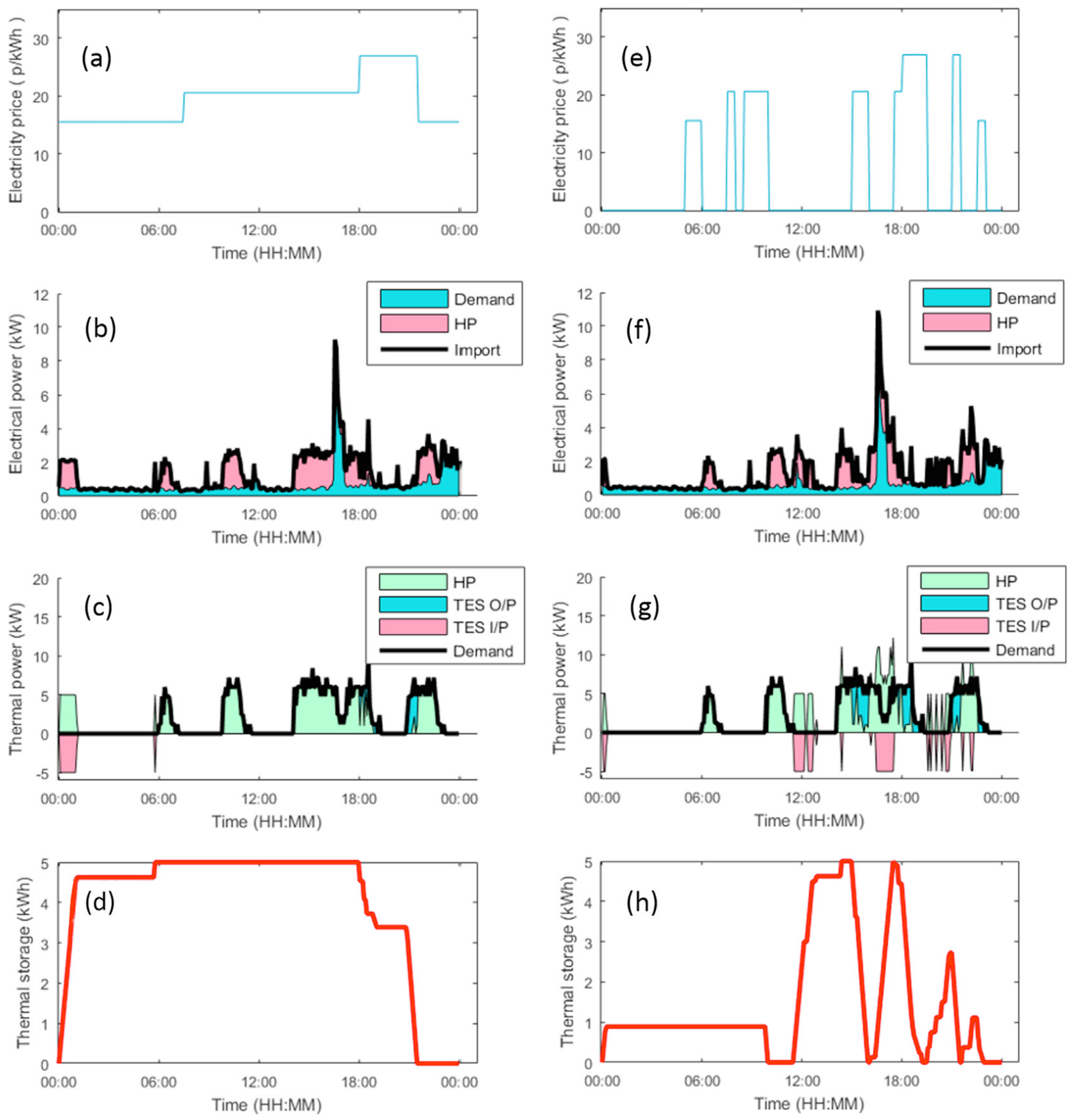

Fig. 2. Operation of the heat pump: Without DTU ((a) to (d)) and with DTU ((e) to (h)).

high heat load occurs at the same time as an electricity load, efficiency gains are not significant. This can be offset to a certain extent because of the presence of a thermal store as seen by the red patches in Fig. 4(c). But utilisation of the Stirling engine cannot match that of fuel cell even with the inclusion of a thermal store as seen in Fig. 4(b). Another disadvantage of the high heat to power ratio is that it prevents the Stirling engine from exporting electricity to the grid.

Utilisation levels go down even further when DTU is enabled. But the cogeneration unit continues to operate when the electricity prices are high as seen in Fig. 4(f). This happens even when there is no heat demand as seen around 9 a.m. in Fig. 4(g). Free electricity prompts more use of the natural gas boiler as seen in Fig. 4(g) in contrast to its counterpart in Fig. 4(c). The use of the thermal store also decreases when DTU is enabled as seen in Fig. 4(h).

4.2. Comparison of overall performance

Equivalent Annual Cost (EAC) is the index used to measure economic performance in this study. It includes annualised capital, operational expenses, and export revenue. A formal definition has been provided in Section 3.3. Fig. 5 presents a comparison of economics with and without Demand Turn Up (DTU).

All technologies are comparable in terms of economic competitiveness when considering the case without Demand Turn Up. High electricity prices lead to high operating costs for the heat pump. It can be seen that the boiler baseline and the resistive heater have similar EACs. This implies that the resistive heater was not offered much scope to charge the thermal store. Thus the resistive heater was not able to reduce the amount of natural gas used. High electricity prices provide conditions that are favourable for the use of fuel cell based cogeneration. There is a considerable decrease in the amount of electricity imported when the fuel cell is in use. Savings from onsite generation of electricity coupled with the revenue from export drive the EAC below the boiler baseline making the fuel cell the only technology that is economically viable. Although high electricity prices favour cogeneration, the Stirling engine does not fare well because of its high heat to power ratio. It is not able to generate enough electricity to reduce import from the grid, resulting in an equivalent annual cost higher than the boiler baseline.

Equivalent Annual Costs of all technologies are lower with Demand Turn Up as seen in Fig. 5. This can be attributed to the reduction in the cost of electricity from the central grid. The introduction of Demand Turn Up tilts the balance in favour of

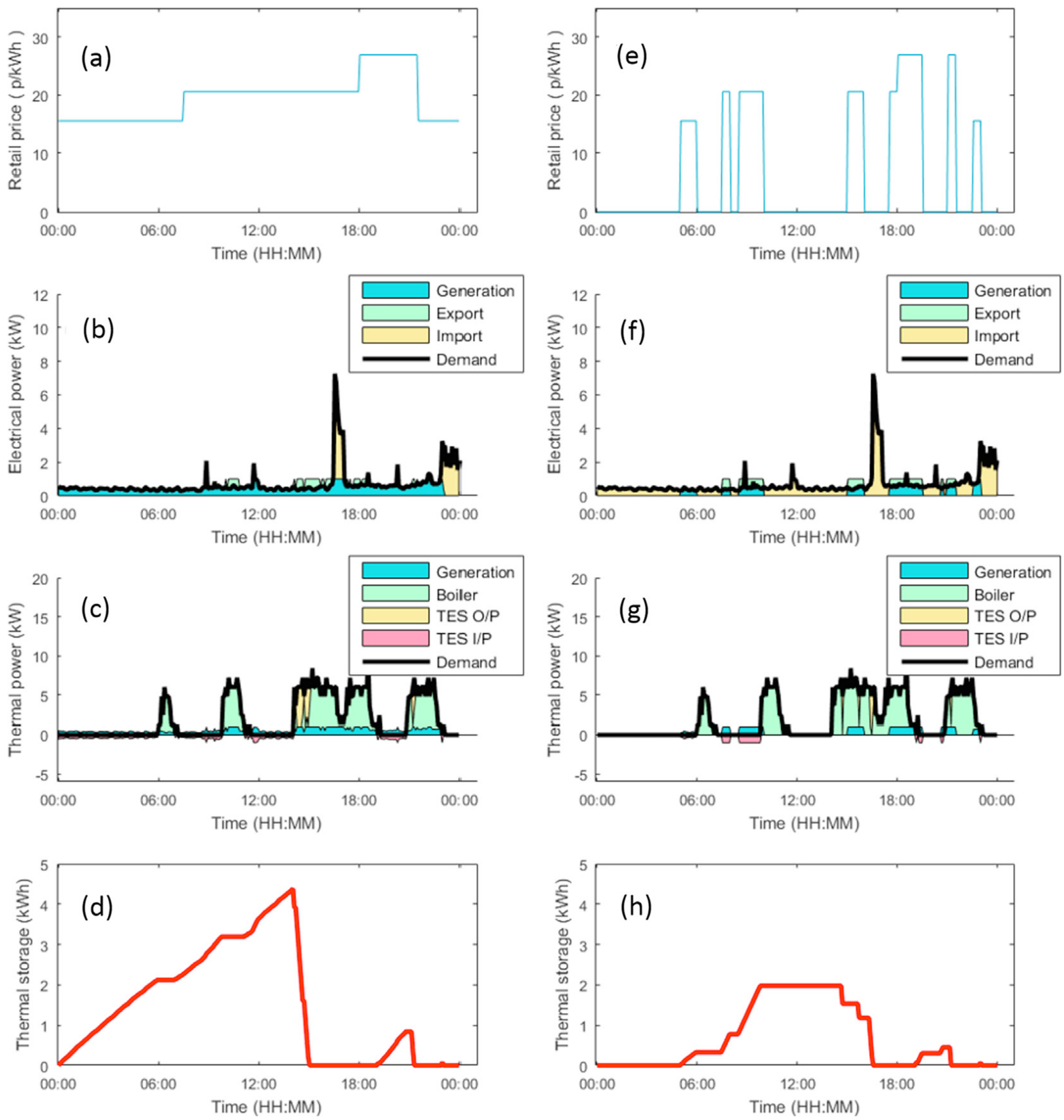

Fig. 3. Operation of the fuel cell: Without DTU ((a) to (d)) and with DTU ((e) to (h)).

technologies that use electricity. The resistive heater and heat pump are able to take advantage of periods with free electricity. Equivalent Annual Costs of both technologies are significantly lower than the boiler baseline. The fuel cell is no longer economically viable. Even though the EAC of the fuel cell has reduced in comparison to the case without Demand Turn Up, the boiler baseline has shifted downwards as well. Savings and revenue from export are not enough to justify investment in the fuel cell. The Stirling engine is able to offset the natural gas boiler enough to result in an EAC lower than the fuel cell.

A comparison of environmental performance is shown in Fig. 6. The heat pump is the clear leader with and without Demand Turn Up. The reason for this is the low carbon intensity of electricity in the low carbon future. The resistive heater is identical to the boiler baseline without Demand Turn Up. This implies that the resistive heater was not used at all in the case without Demand Turn Up. The resistive heater is able to produce emissions lower than the boiler baseline when Demand Turn Up is enabled. Although emissions from electricity import have increased, reduced reliance on the natural gas boiler has lowered the overall emissions from the resistive heater. Emissions from both fuel cell and Stirling engine cogeneration units are above the boiler baseline with and without Demand Turn Up. Accounting for onsite generation lowers the net emission values slightly but not enough to drive them below the boiler baseline.

5. Conclusion

In this article we have evaluated the potential for using residential heating systems as a means to absorb surplus renewables in low carbon futures. The system aims to implement Demand Turn Up by offering free electricity during periods of excess renewable generation. Particular emphasis is laid on the operating strategies and economic and environmental performance of the different heating technologies considered.

Technologies which make use of electricity thrive when Demand Turn Up is enabled. Demand Turn Up allows the resistive heater and the heat pump to capitalise on the occurrence of zero electricity prices. These technologies are able to charge the thermal store using free electricity and discharge the thermal store when electricity prices are high. The savings from such actions are enough to reduce the equivalent annual cost by 50% for the resistive heater and by 60% for the heat pump.

Cogeneration units on the other hand do not perform well when

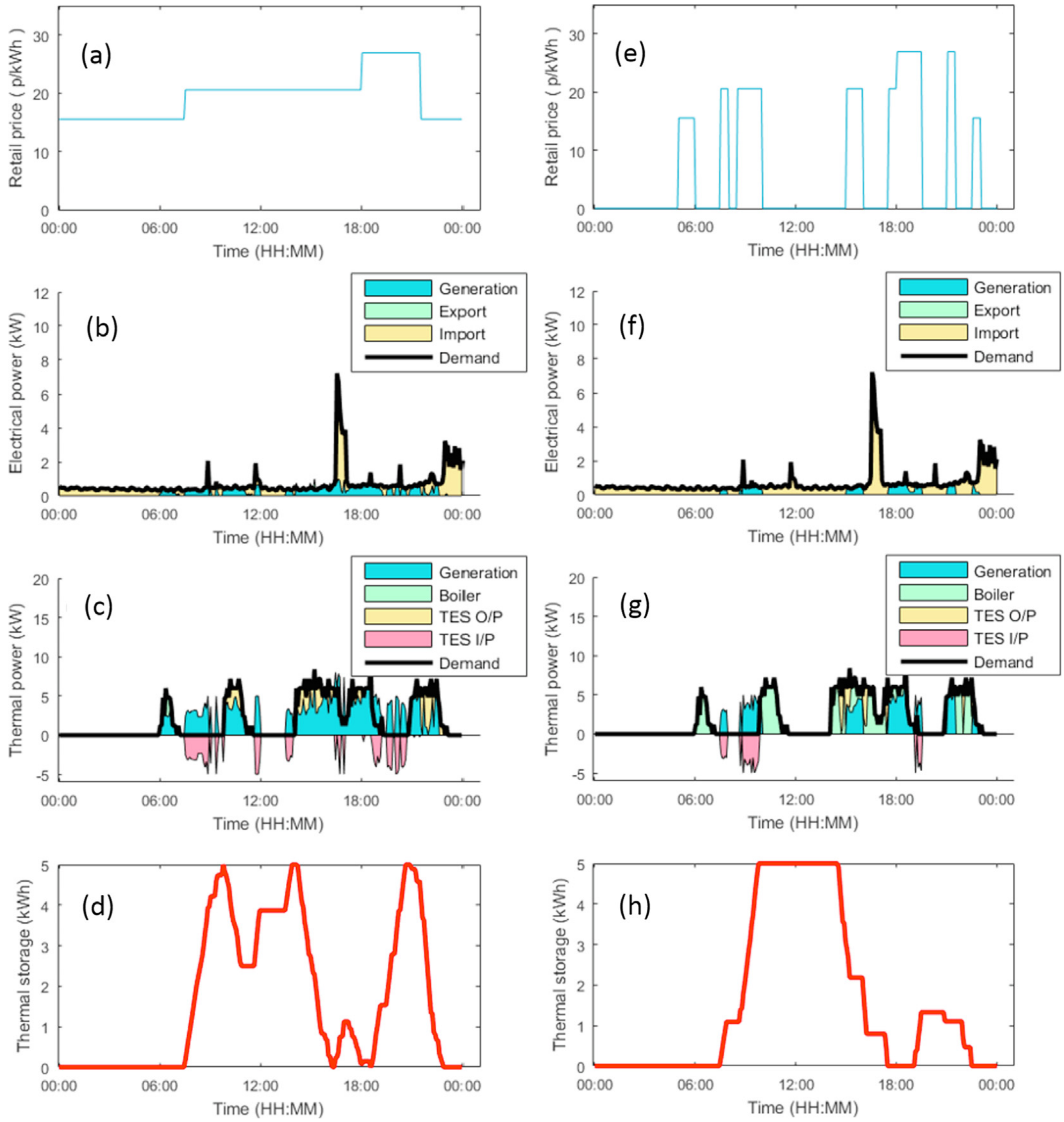

Fig. 4. Operation of the stirling engine: Without DTU ((a) to (d)) and with DTU ((e) to (h)).

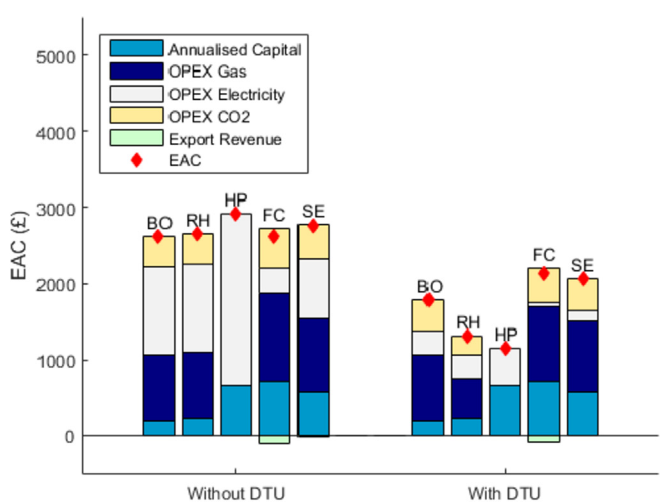

Fig. 5. Comparison of Equivalent Annual Cost. (DTU – Demand Turn Up, BO—Boiler, RH—Resistive heater, HP—Heat pump, FC—Fuel cell micro cogeneration, SE—Stirling engine micro cogeneration).

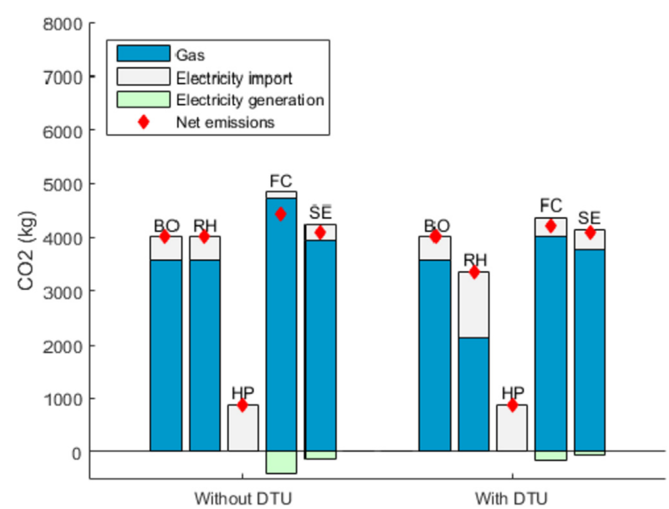

Fig. 6. Comparison of Emissions. (DTU – Demand Turn Up, BO—Boiler, RH—Resistive heater, HP—Heat pump, FC—Fuel cell micro cogeneration, SE—Stirling engine micro cogeneration).

Demand Turn Up is enabled. The lowering of electricity prices to zero diminishes the value gained out of combined generation of heat and power. These technologies are to be avoided in systems with Demand Turn Up since they are not meant to increase consumption and they are not economically viable.

Technology adoption will not only be based on performance but also ease of installation and upfront cost of the technology. Heat pumps are disadvantaged by high upfront costs and inconveniences associated with installation. Issues related to upfront costs can be alleviated by policy support but the pains related to installation still remain. Resistive heaters are relatively easy to install and involve low upfront costs. Hence resistive heaters are likely to be the technology of choice for implementing Demand Turn Up, though this could lead to significantly higher primary energy consumption with related environmental impacts.

Future research can consider the integration of models describing the supply and demand sides. This is important since there is a possibility of rebound peaks appearing due to a large number of devices reacting to a single price signal. Staggered price change according to location and density of flexible devices can help avoid such peaks. Another factor that requires attention is the uncertainty associated with forecasts of excess renewable generation. Stochastic programming can be used to address the risks related to intermittent resources. And finally, the inclusion of electric storage is another interesting direction that can help improve performance of the systems considered.

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Appendix A. Sample Day Selection Algorithm

This section describes how the typical days were selected. Three parameters drive the selection process: coincidence, thermal demand and electrical demand. Instantaneous coincidence for the current time period is defined as the lower value when comparing electrical and thermal demand. The algorithm makes use of the sum of all instantaneous coincidence values in a day. While thermal and electrical demand values are expected indices for sample day selection, coincidence is not. This is done because coincidence of electrical and thermal demand is a deciding factor for micro cogeneration performance. This parameter determines the savings that can be gained via the combined production of heat and power. The following steps are repeated for every season.

Sequence	Description
Step 1	Calculate sum of all instantaneous values for each day for the three parameters mentioned: coincidence, thermal demand and electrical demand. This provides us with a total value for each parameter in each day of sample data.
Step 2	Calculate the mean of the total values for all days. This overall mean is calculated for all three parameters.
Step 3	Calculate relative deviation of total values for each day from the overall mean. Relative deviation for each day = (Day total − Overall mean)/(Overall mean) Again this is done for all three parameters.
Step 4	An error value is assigned to each day. This error is the sum of relative deviations for the three parameters.
Step 5	Pick the day with the least error value.

Appendix B. List of Symbols

SETS	
T	Set of all time periods $t \in T$
K	Set of all sample days $k \in K$
PARAMETERS	
α_{gas}	Natural gas price (p/kWh)
α_{CO2}	Non-traded price of carbon (£/tonne)
α_t^{imp}	Retail price of electricity (p/kWh)
$\alpha_t^{wholesale}$	Wholesale price of electricity (p/kWh)
η_B	Efficiency of natural gas boiler
η_{ch}	Charging efficiency of thermal energy storage
η_{disch}	Discharging efficiency of thermal energy storage
η_{el}	Electrical efficiency of CHP unit
η_{th}	Thermal efficiency of CHP unit
η_{EH}	Efficiency of resistive heater
E	Annual carbon emissions (kg)
Φ	Equivalent Annual Cost (£)
Ψ	Upfront cost of heating technology (£)
$\mathrm{A}^{wholesale}$	Mean value of wholesale price of electricity (p/kWh)
$\overline{B}$	Capacity of natural gas boiler (kW)
COP_{HP}	Coefficient of Performance of the heat pump
D_t^{el}	Electricity demand in the heating system model (kW)
D_t^{th}	Thermal demand in the heating system model (kW)
e_{gas}	Carbon intensity of natural gas (kg/kWh)
e_{el}	Carbon intensity of electrical grid (kg/kWh)
L	Lifetime of heating technology (years)
$\overline{P^{el}}$	Electrical capacity of CHP unit (kW)
$\overline{P^{RH}}$	Capacity of resistive heater (kW)
$\overline{P^{HP}}$	Capacity of heat pump (kW)
r	Discount rate (%)
$\overline{S}$	Capacity of thermal energy storage (kWh)
T_{end}	End of the planning horizon for the heating system model
w_k	Weight of sample day k (Days)
BINARY VARIABLES	
ϕ_t^+	Charging mode indicator for thermal energy storage
ϕ_t^-	Discharging mode indicator for thermal energy storage
CONTINUOUS VARIABLES	
β_t	Operating cost of the heating system (£)
γ_t	Export revenue generated by the heating system (£)
λ	Objective function in the heating system (£)
Φ	Equivalent Annual Cost of heating technology (£)
B_t	Thermal output of the boiler in period t (kWh)
E	Annual carbon emissions (kg)
P_t^{exp}	Electricity exported by CHP unit in period t (kW)
P_t^{el}	Electricity generated by the CHP unit (kW)
P_t^{RH}	Electricity consumed by resistive heater in period t (kW)
P_t^{HP}	Electricity consumed by heat pump in period t (kW)
P_t^{imp}	Electricity imported in period t (kW)
P_t^{th}	Thermal output of CHP unit in period t (kW)
R_t^+	Charging of thermal energy storage (kW)
R_t^-	Discharge from thermal energy storage (kW)
S_t	Storage level in the thermal energy storage (kWh)

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